G-008/GR-92-400 FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER

MINNEGASCO COMPANY ISSUE DATE: **Projected 4/30/93**
DOCKET NO: G-008/GR-92-400

FINDINGS OF FACT, CONCLUSIONS
OF LAW, AND ORDER

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BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

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| In the Matter of the Application of Minnegasco, a Division of Arkla, Inc., for Authority to Increase its Rates for Natural Gas Service in Minnesota | ISSUE DATE: May 3, 1993<br><br>DOCKET NO. G-008/GR-92-400<br><br>FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER |

## PROCEDURAL HISTORY

### I. INITIAL PROCEEDINGS

On July 2, 1992, Minnegasco, a Division of Arkla, Inc. (Minnegasco or the Company), filed a petition seeking a rate increase of $24,822,800 or approximately 5.5 percent over existing rates. The Company filed its direct testimony in support of this increase as part of its rate case filing.

On August 17, 1992, the Commission issued Orders accepting the Company's filing, suspended the proposed rates, and set the matter for contested case hearing. The Office of Administrative Hearings assigned Administrative Law Judge Richard Luis to the case.

On August 27, 1992, the Administrative Law Judge (ALJ) convened a prehearing conference.

On August 31, 1992, the Commission issued its ORDER SETTING INTERIM RATES, authorizing an interim rate increase of $11.8 million or 2.6 percent, effective September 1, 1992.

On September 14, 1992, Minnegasco made a supplemental filing of additional direct testimony and exhibits concerning the Weather Normalization Adjustment (WNA) and Financial Accounting Standard (FAS) 106.

On September 17, 1992, the ALJ issued a Prehearing Order granting the Petitions to Intervene of the Minnesota Department of Public Service (the Department), the Residential Utilities Division of the Office of the Attorney General (RUD-OAG), Honeymead Products Company (Honeymead), Minnesota Energy Consumers (MEC), Northern Natural Gas Company (Northern), and the Suburban Rate Authority (SRA). The ALJ's Order also established the hearing schedule and procedural guidelines governing the conduct of the case.

On October 26, 1992, the Department, RUD-OAG, MEC and SRA filed their direct testimony.

On November 10, 1992, the Commission issued an Order granting Minnegasco's motion to enlarge the time to object to Gas, Inc.'s petition to intervene and denying Gas, Inc.'s petition.

On or about November 20, 1992, the parties filed Rebuttal Testimony and on December 2, 1992 they filed Surrebuttal Testimony.

## II. PARTIES AND REPRESENTATIVES

### A. Intervenors

The intervenors and their representatives in this matter are as follows:

Minnesota Department of Public Service (the Department) represented by Scott Wilensky and Mark Chalfant, Special Assistant Attorneys General, 1100 Bremer Tower, Seventh Place and Minnesota Street, St. Paul, Minnesota 55101;

Residential Utilities Division of the Office of the Attorney General (RUD-OAG) represented by Gary R. Cunningham, Special Assistant Attorney General, 340 Bremer Tower, Seventh Place and Minnesota Street, St. Paul, Minnesota 55101;

Honeymead Products Company (Honeymead) represented by Rebecca J. Heltzer, McGrann, Shea, Franzen, Carnival, Straughn & Lamb, 1700 Lincoln Center, 333 South 7th Street, Minneapolis, Minnesota 55402-2436;

Minnesota Energy Consumers (MEC) represented by James J. Bertrand, Leonard, Street & Deinard, 50 South 5th Street, Suite 2300, Minneapolis, Minnesota 55402-2436;

Northern Natural Gas Company (Northern) represented by Patrick J. Joyce, P.O. Box 3330, Omaha, Nebraska 68102-0330; and

Suburban Rate Authority (SRA) represented by James M. Strommen, Holmes & Graven, 470 Pillsbury Center, Minneapolis, Minnesota 55402.

### B. The Company

Minnegasco was represented by Brenda Bjorklund, Miggie E. Cramblit, and John C. Sprangers, 201 South Seventh Street, Minneapolis, Minnesota 55402, Sally A. Johnson, Faegre & Benson, 2200 Norwest Center, 90 South Seventh Street, Minneapolis, Minnesota 55402-3901, and Paul T. Ruxin, Jones, Day, Reavis & Pogue, 901 Lakeside Avenue, Cleveland, Ohio 44114.

## III. PUBLIC HEARINGS AND PUBLIC TESTIMONY

The ALJ held public hearings to receive comments and questions from non-intervening ratepayers. The dates and locations of these hearings are listed below:

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| November 10, 1992 | Minneapolis |
| November 10, 1992 | Bloomington |
| November 18, 1992 | Mankato |
| November 19, 1992 | Willmar |

In Minneapolis, 30 persons attended and four spoke. The four speakers addressed, in turn, their concerns regarding Minnegasco's rate structure, interruptible service, service contracts, and the delivery rate on gas purchased by the customer from a third party.

In Bloomington, of the 19 persons attending, three spoke. The first speaker questioned Minnegasco's rate increase in light of reductions in the cost of gas since 1983, criticized Minnegasco's billing practices, and objected to BTU billing. The second speaker questioned Minnegasco's willingness to invest in storage gas if it wasn't allowed a return on that investment. The third speaker requested clarification regarding Minnegasco's distribution and fixed costs and opposed the increase in rates and monthly customer fee in light of declining real incomes.

In Mankato and Willmar, 15 and 10 persons attended, respectively, but none spoke. In addition, the Commission received several dozen written comments from affected ratepayers. Generally, the commentators opposed any rate increase, especially on low income or fixed income persons. The comments stressed the pressure of increasing the cost of a basic necessity of life.

## IV. EVIDENTIARY HEARINGS

The ALJ held evidentiary hearings on December 8-11, 14-16, 18, and 21, 1992 in St. Paul, Minnesota.

## V. PROCEEDINGS BEFORE THE COMMISSION

On December 4, 1992, four of the parties (Minnegasco, the Department, RUD-OAG, and the SRA) filed with the ALJ an Offer of Partial Settlement.

On December 31, 1992, the ALJ issued an Order submitting the proposed Settlement to the Commission to determine whether the Settlement was in the public interest and supported by substantial evidence in the record. The ALJ stated that he found the Offer of Partial Settlement to be reasonable and supported by substantial evidence. The ALJ recommended that the Commission accept the Offer of Partial Settlement as resolving the financial and rate design issues encompassed therein.

On December 30, 1992, the same parties filed with the ALJ an Amended Offer of Partial Settlement. The Amended Settlement included agreements reached by the parties on additional issues since the start of the evidentiary hearing on December 8, 1992 and made certain clerical and computational changes.

On January 29, 1993, the ALJ issued an Order submitting the proposed Amended Offer of Partial Settlement (Settlement) to the Commission to determine whether the Settlement was in the public interest and supported by substantial evidence in the record. The ALJ stated that he found the Settlement to be reasonable and supported by substantial evidence. The ALJ recommended that the Commission accept the Settlement as resolving the financial and rate design issues encompassed therein.

On February 19, 1993, the Commission met to deliberate upon the matter and decided to accept the Amended Offer of Partial Settlement in its entirety.

On March 8, 1993, the ALJ filed his final report and recommendations regarding the remaining contested issues.

On March 19, 1993, the Commission met on its own motion to reopen deliberations regarding its February 19, 1993 decision to accept the Offer of Partial Settlement. After further deliberations, the Commission left its acceptance of the Settlement unchanged.

On March 31, 1993, the Commission heard oral arguments from the parties and on April 1 and 2, 1993 the Commission met to deliberate this matter.

Upon review of the entire record of this proceeding, the Commission makes the following Findings of Fact, Conclusions of Law, and Order.

## FINDINGS AND CONCLUSIONS

### VI. JURISDICTION

The Commission has general jurisdiction over the Company under Minn. Stat. §§ 216B.01 and 216B.02 (1992). The Commission has specific jurisdiction over rate changes under Minn. Stat. § 216B.16 (1992).

The case was properly referred to the Office of Administrative Hearings under Minn. Stat. §§ 14.48-14.62 (1992) and Minn. Rules, Part 1400.0200 et seq.

### VII. FURTHER ADMINISTRATIVE REVIEW

Under Minn. Rules, Part 7830.4100, any petition for rehearing, reconsideration, or other post-decision relief must be filed within 20 days of the date of the Order. Such petitions must be filed with the Executive Secretary of the Commission, must specifically set forth the grounds relied upon and errors claimed, and must be served on all parties. The filing should include an original, 13 copies, and proof of service on all parties.

Adverse parties have ten days from the date of service of the petition to file answers. Answers must be filed with the Executive Secretary of the Commission and must include an original, 13 copies, and proof of service on all parties. Replies are not permitted.

The Commission, in its discretion, may grant oral argument on the petition or decide the petition without oral argument.

Under Minn. Stat. § 216B.27, subd. 3 (1992), no Order of the Commission shall become effective while a petition for rehearing is pending or until either of the following: ten days after the petition for rehearing is denied or ten days after the Commission has announced its final determination on rehearing, unless the Commission otherwise orders.

Any petition for rehearing not granted within 20 days of filing is deemed denied. Minn. Stat. § 216B.27, subd. 4 (1992).

### VIII. MINNEGASCO

Minnegasco is an operating division of Arkla, Inc. and maintains its principal office in Minneapolis, Minnesota. At the beginning of this matter, Minnegasco distributed natural gas at retail to customers in three states: Nebraska, South Dakota, and Minnesota. During the hearing, Minnegasco announced its plans to sell its Nebraska properties and trade its South Dakota properties for additional Minnesota properties.[1] At the end of 1991, the Company had approximately 499,539 customers in Minnesota, and an annual throughput of approximately 123 billion cubic feet. The largest metropolitan areas served are Minneapolis and the West Metro suburbs. Additionally, the Company has a significant large volume load.

## IX. BURDEN OF PROOF

Minn. Stat. § 216B.16, subd. 4 (1992) states: "The burden of proof to show that the rate change is just and reasonable shall be upon the public utility seeking the change."

The Minnesota Supreme Court has articulated standards for the burden of proof in rate cases. In the Matter of the Petition of Northern States Power Company for Authority to Change Its Schedule of Rates for Electric Service in Minnesota, 416 N.W. 2d 719 (Minn. 1987). In the Northern States Power case, the Court divided the ratemaking function of the Commission into quasi-judicial and legislative aspects. The Commission acts in a quasi-judicial mode when it determines the validity of facts presented. Just as in a civil case, the burden of proof is on the utility to prove the facts by a fair preponderance of the evidence. Such items as claimed costs or other financial data are facts which the utility must prove by a fair preponderance of the evidence.

The Commission acts in a legislative mode when it weighs the facts presented and determines if proposed rates are just and reasonable. Acting legislatively, the Commission draws inferences and conclusions from proven facts to determine if the conclusion sought by the utility is justified. The Commission weighs the facts in light of its statutory responsibility to enforce the state's public policy that retail consumers of utility services shall be furnished such services at reasonable rates. In its legislative capacity, the Commission forms determinations such as the usefulness of a claimed item, the prudence of company decisions, and the overall reasonableness of proposed rates.

The utility therefore faces a two part burden of proof in a rate case. When presenting its case in the rate change proceeding, the utility has the burden to prove its facts by a fair preponderance of the evidence. The utility also has the burden to prove, by means of a process in which the Commission uses its judgment to draw inferences and conclusions from proven facts, that the proposed rates are just and reasonable.

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[1] This transaction is being reviewed separately in Docket No. G-008, 010/PA-93-92, In the Matter of a Joint Petition From Minnegasco and Midwest Gas for Authority to Exchange Assets, Utility Operations and Business.

## X. TEST YEAR

Minnegasco used the period July 1, 1992 through June 30, 1993 for its test year. Accordingly, the financial data submitted by the Company was largely projected. No party objected to the Company's test year period. Minnegasco's test year was used but not specifically addressed in the Offer of Partial Settlement or in the ALJ's report.

The Commission finds that the Company's use of a twelve-month test year ending June 30, 1993 was appropriate in this proceeding.

## XI. OFFER OF PARTIAL SETTLEMENT ACCEPTED AND ADOPTED

The Commission finds that the Amended Offer of Partial Settlement (the Settlement) is supported by substantial evidence, promotes the public interest, and (in conjunction with the resolution of the remaining contested issues in this Order) will result in just and reasonable rates. The Commission will accept and adopt the Settlement.[2] A copy of the Settlement is incorporated into this Order by reference. The non-proprietary version of the Settlement is attached to this Order.

A Stipulation of Facts accompanied the Settlement. The parties set forth the evidentiary basis for their resolutions of individual issues and explained their basis in reason and policy. In addition, the parties made their witnesses available for questioning by Commission staff to clarify the evidentiary basis for Settlement positions if necessary. Since the Commission must base its rate case decisions on the record, this increased the Settlement's value and credibility. Minn. Stat. § 14.60, subd. 2 (1992). While the Commission could have approved the Settlement based solely on its independent review of the record, it is reassuring that the parties demonstrated that the record was central to their negotiations on every issue.

In non-ratemaking settlement negotiations it is common for parties to concede some issues to obtain a more favorable resolution of others they value more highly. This is reasonable and appropriate in private disputes, where the goal of the settlement process is to reach a result satisfactory to all parties. In Commission proceedings, however, the Commission's responsibility is to serve the public interest. This fundamental responsibility does not change when considering the proposed

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[2] Minnesota Energy Consumers (MEC), a party to this proceeding but a non-signatory of the Settlement, challenged the reasonableness of the Settlement's revenue apportionment. As discussed in greater detail in the Rate Design section of this Order (page 25, infra), the Commission rejected MEC's challenge and found that the revenue apportionment proposed in the Settlement was fair and reasonable.

settlement of a rate case. The Commission certainly considers the monetary and administrative efficiency benefits of not subjecting settled issues to a fully contested case treatment. However, the Commission also scrutinizes a proposed settlement to see whether it protects the interests of the Company, the public, and all customer classes. To assure that this objective is achieved, the Commission examines to see that every issue is resolved within the bounds of acceptable regulatory practice. This is particularly important in rate case settlements because resolution of individual issues not only affects rate levels and structures adopted in this proceeding but has implications on future rate levels and rate structures.

The Commission is convinced that the Settlement proposed in this matter meets that standard. Each issue addressed in the Settlement has been resolved within the established parameters of acceptable regulatory practice. Accordingly, the Commission will accept the Settlement.

This is not to say that if the Commission had considered the issues resolved in the Settlement on the merits in a contested context the Commission would have decided these issues the same way that they were settled. The Commission has serious concerns regarding a number of the settled issues, including Minnegasco's capital structure, incentive plan costs, manufactured gas plant costs, and appliance service regulated/non-regulated cost allocations. The Commission notes that its acceptance of the Settlement in no way provides precedent on how it would resolve the issues contained therein in future rate cases, other than that the Settlement treatment of the issue was within the range of acceptable regulatory practice. In sum, acceptance of the Settlement does not diminish the Commission's discretion in future rate cases to choose other options that fall within the range of reasonable regulatory practice.

Additional Filing Requirements

To underscore the Commission's particular concern regarding the resolution of certain issues, the Commission will require further attention to the following issues:

1. Definition of MGP Costs - Minnegasco's proposed and stipulated recovery amounts for Manufactured Gas Plant cleanup costs were categorized by amounts for remediation, legal services, investigation, and amortization. Minnegasco projected amounts in these categories that totaled over $5 million. In its compliance filing within 60 days of this Order, the Company will be required to provide further definition of these costs, including the breakdown of costs that would be internal, external, legal, consulting, contracting, and other. Utility regulatory costs, if any, shall also be shown.

2. MGP Cost Recovery Efforts - In its compliance filing within 60 days of this Order, the Company also will be required to provide an update of its insurance recovery activities and plans,

including what claims it has filed and what efforts have been made and will be made to identify and recover from other potential parties involved.

3. Annual Report of MGP Costs - Minnegasco will be required to file annually a report of its MGP cleanup costs and MGP cost recoveries.

4. Other issues - The Commission expects that the parties will address the merits of all the settled issues in future rate cases and will require the Company, in its next rate case filing, to describe 1) the treatment of incentive compensation, vacation accrual, and winter leak surveys in the test year costs, and 2) the impact on the revenue requirement of using an industry average capital structure.

## XII. REMAINING CONTESTED FINANCIAL ISSUES

### A. Financial Accounting Standard 106

#### 1. Factual Background

In December of 1990 the Financial Accounting Standards Board, the professional association that sets accounting standards for American finance and business, issued a new standard on the appropriate accounting treatment of certain post-employment benefits. These benefits are known as PBOPs, for "Post-retirement Benefits Other than Pensions." The main benefit in this category is health insurance, but life insurance, dental insurance, and miscellaneous benefits are also included. The new accounting standard requires companies to account for PBOPs on an accrual basis. In the past nearly all Minnesota utilities, including Minnegasco, have recorded these expenses on a cash basis.

Under cash basis (pay-as-you-go) accounting, PBOP expenses are not recognized on a company's books until payment is made. Under accrual accounting, these expenses are recognized on a pro-rata basis during an employee's period of service, as the obligation to pay arises. In a recent all-utility proceeding, the Commission adopted Financial Accounting Standard 106 for recordkeeping and ratemaking purposes, subject to review of all expenses for prudence and reasonableness.[3] The Order in that proceeding authorized Minnesota utilities to shift to accrual accounting to record future PBOP obligations as they are incurred. It also authorized utilities to use deferred accounting to record PBOP costs in excess of those that would have been recorded under cash basis accounting.

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[3] <u>In the Matter of the Accounting and Ratemaking Effects of the Statement of Financial Accounting Standards No. 106</u>, Docket No. U-999/CI-92-96, ORDER ADOPTING ACCOUNTING STANDARD AND ALLOWING DEFERRED ACCOUNTING (September 22, 1992).

To avoid prolonged uncertainty about the rate effects of the new accounting standard, the Commission limited deferred accounting to three years. Companies were required either to secure a ratemaking determination during that time or to forfeit any ability to recover deferred amounts in rates. This general rate case is the first proceeding in which the Commission has been asked to rule on the recoverability of the costs measured using the new FASB standard.

No party challenges the accuracy of the Company's calculations of current PBOP service costs being incurred for active employees or the recovery of these costs in rates. The Commission, too, finds the current service costs of the current plan reasonable, prudent, and recoverable in rates.

The remaining issue is the recoverability of Minnegasco's "transition obligation," the unrecognized amount of accumulated PBOPs as of the Company's adoption of the new accounting standard on January 1, 1993. Amortization of the transition obligation is a significant component of the revenue deficiency claimed in this rate case. The amortization, plus associated interest, accounts for roughly $3.4 million of the annual rate increase sought by the Company.

Minnegasco has calculated its transition obligation using the formula prescribed by the Financial Accounting Standards Board (FASB). The total obligation is calculated on the basis of the cost of the Company's current PBOP plan, as required by FASB. The Company proposes to amortize the obligation over 14 years, which is acceptable under FASB guidelines. No party challenges the accuracy of the Company's calculations, which the Commission, too, accepts as accurate. The other parties do, however, challenge the reasonableness of allowing full recovery of the transition obligation and associated interest and the reasonableness of the proposed 14-year amortization period.

The Department and the RUD-OAG recommend disallowing 50 percent of the transition obligation, and associated interest, on grounds that an expense so extraordinary and unrepresentative of test year expense should be shared by ratepayers and shareholders. The SRA recommends total disallowance on grounds that the Company was imprudent in failing to adopt accrual accounting sooner. The Administrative Law Judge recommended granting recovery of the entire transition obligation and associated interest.

### 2. Accounting Principles Do Not Control Ratemaking

The Commission notes that costs can be treated differently for accounting and ratemaking purposes. As the Minnesota Supreme Court has explained,

> Nothing in the federal regulations or the Minnesota Rules suggests that the system of accounts is determinative of the treatment of any item for purposes of setting rates or that the system deprives MPUC of

> its power or absolves it of the duty to decide the issues before it and to set just and reasonable rates.
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> Petition of Continental Telephone Company, 389 N.W.2d 910, 915 (Minn. 1986).

### 3. Commission Action

The Commission will allow recovery of 50 percent of the transition obligation and associated interest, establish a 20-year amortization period, and authorize internal funding, for the reasons set forth below.

#### a. The Transition Obligation is an Out-of-Test-Year Expense

In every general rate case, the Commission bases rates on a representative slice of the utility's normal operations called the "test year." The main purpose of the test year is to ensure that rates are based on facts and experience instead of conjecture. It is also intended to replace the fiscal discipline of the marketplace, which is absent for monopolies, with the fiscal discipline of prior determination of reasonable costs. Finally, and most significantly in this case, it is intended to ensure as much precision as possible in matching the time a cost is incurred with the time it is recovered from ratepayers.

This final goal, matching the time a cost is incurred with the time it is recovered, is one of the most important functions of regulation. Since utility service is a public necessity provided in a monopoly environment, rates must be set to recover the full cost of providing service while they are in effect. Placing any portion of the cost of service on preceding or succeeding ratepayers raises grave issues of fairness, as well as resource allocation. As a general rule, it is inequitable and economically unsound to ask one "generation" of captive ratepayers to bear the cost of providing service to another.

Second, matching the time that costs are incurred to the time that they are recovered protects the integrity of the ratemaking process by ensuring that only representative, not aberrant, costs are included in rates. Regulatory commissions assume that actual costs will vary slightly from test year costs. Under normal circumstances, however, utilities are expected to place their costs in test year categories or bear them themselves. The Commission does not normally adjust test year costs to reflect non-test year expenses. As the Commission explained in an earlier Order:

> . . . the test year method by which rates are set rests on the assumption that changes in the Company's financial status during the test year will be roughly symmetrical -- some favoring the Company, others not. Not adjusting for either type of change maintains this symmetry and maintains the integrity of the test year

process. Anomalies are likely to exist in and beyond any test year.

> <u>In the Matter of the Petition of Minnesota Power & Light Company, d/b/a Minnesota Power, for Authority to Change Its Schedule of Rates for Retail Electric Service in the State of Minnesota</u>, Docket No. E-015/GR-87-223 ORDER AFTER RECONSIDERATION AND REHEARING (May 16, 1988).

Finally, utilities do not face the same pressure as unregulated enterprises to monitor costs precisely and continuously. The test year, and the time matching it forces, are valuable tools for ensuring that costs are promptly and properly identified, recognized, and recovered. In short, the test year is an important regulatory safeguard against under-recovery, over-recovery, and imprecision in ratemaking.

Since the transition obligation is an accounting adjustment for obligations incurred but not recognized in the past, it is an out-of-test-year expense that would normally be disallowed. The Commission believes there are sound reasons for allowing part of it in this case, however.

#### b. Partial Recovery of the Transition Obligation is Equitable

First of all, the costs represented in the transition obligation are costs whose recovery has been allowed in past ratemakings under cash basis accounting. Furthermore, in recording these expenses on a cash basis in the past, Minnegasco was following established accounting and regulatory practice. To disallow them entirely now because of a change in generally accepted accounting principles would be unduly harsh.

At the same time, however, placing the entire transition obligation in rates would be less than equitable. Although the ratepayers are now paying retirees' PBOPs under cash basis accounting, converting both retirees' and current employees' PBOPs to accrual accounting results in just the sort of overlap of past and current costs the test year concept is designed to avoid. It results in one group of ratepayers bearing expenses that would have been charged to another group, given perfect information earlier. Furthermore, the financial burden of the accounting change is substantial, increasing annual PBOP expense by some 350 percent. Placing the entire burden on ratepayers, then, cannot be done lightly.

Finally, although the new accounting standard benefits all stakeholders by enhancing the accuracy of corporate financial statements, it benefits investors so significantly that apportioning part of the transition cost to them is reasonable. It is the investment community, after all, who has the greatest interest in the financial condition and prospects of individual companies, and the greatest need to make valid comparisons between them. It is these needs FAS 106 was designed to meet. Of course, ratepayers also benefit from meaningful financial disclosure and the confidence it produces in investors. Under these circumstances, the Commission concludes allowing recovery of 50 percent of the transition adjustment in rates is reasonable.

It is also consistent with Commission action in other cases involving extraordinary expenses that do not fit within established rate case categories. In such cases the Commission has not considered itself bound to allow or disallow the expenses in their entirety, but has instead sought creative and judicious regulatory treatment. See, for example, the decision in Minnesota Power's 1987 rate case partially disallowing the costs of maintaining excess capacity[4] and the decision in NSP's 1986 rate case apportioning manufactured gas plant clean up costs between ratepayers and shareholders.[5]

Other regulatory bodies have taken similar approaches. The Illinois Commerce Commission, for example, has determined that coal tar clean up costs should be apportioned equally between ratepayers and shareholders.[6] The Vermont Public Service Board has found that the costs of a management incentive plan should be allocated equally between ratepayers and shareholders. In Re Green Mountain Power Corporation, 119 PUR 4th 62 (Vermont Public Service Board 1991).

### c. Full Recovery of the Transition Obligation Not Required for Investor Confidence

The Commission rejects the Company's claim that failure to include the entire transition obligation in rates is likely to adversely affect investors' perception of the Minnesota regulatory environment and drive up the Company's cost of capital. The Commission believes that this Order speaks for itself and will be properly interpreted by the investment community. The Commission has consistently included, and will continue to include, all allowable costs in rates. The Commission will continue to seek innovative and equitable

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[4] In the Matter of the Petition of Minnesota Power & Light Company, d/b/a Minnesota Power, for Authority to Change Its Schedule of Rates for Retail Electric Service in the State of Minnesota, Docket No. E-015/GR-87-223 FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER (March 1, 1988).

[5] In the Matter of the Petition of Northern States Power Company for Authority to Change its Schedule of Rates for Gas Utility Service Within the State of Minnesota, Docket No. G-002/GR-86-160, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER (January 27, 1987).

[6] Re Coal Tar Cleanup Expenditures, Docket No. 91-0080 et al, Order dated September 30, 1992.

approaches to costs, such as the transition obligation, that do not qualify for automatic inclusion in rates.

### d. Total Disallowance Not Required for Failure to Adopt Accrual Accounting Sooner

The Suburban Rate Authority (SRA) argued that the entire transition obligation should be disallowed because the Financial Accounting Standards Board had indicated as early as 1979 that it was rethinking its position allowing cash basis accounting for PBOPs. The SRA contended the prudent course would have been to seek Commission approval to implement accrual accounting earlier.

The Commission agrees with and adopts Findings 46 and 53 of the Administrative Law Judge rejecting this claim. It was prevailing business practice, and the preferred practice under generally accepted accounting principles, to record PBOPs using cash accounting. The Commission believes the Company acted prudently in waiting for the new accounting standard to be issued before converting to accrual accounting.

### e. External Funding of PBOPs Unnecessary

The Company proposed that it be allowed to fund its PBOP obligation internally, arguing that its strong equity position made external funding unnecessary and that its inability to use tax-deductible funding vehicles made it counterproductive. No party opposed internal funding, and the Administrative Law Judge recommended it.

The Commission agrees that internal funding offers adequate security and clear cost advantages at present. The Commission will require the Company to file an annual report with the Department of Public Service, however, detailing amounts accrued in the internal fund, amounts expended, projected future accruals and expenditures, the feasibility of alternative funding options (including tax-deductible funding options), and Company equity levels. This report will allow continuous monitoring of the internal fund and prompt identification of any conditions warranting re-examination of external funding.

### f. 50 Percent of the Interest on the Transition Obligation Allowed

The Company seeks recovery of both the transition obligation and associated interest. The transition obligation consists of unrecognized PBOP obligations, reduced to present value. Interest on those obligations for the time between accrual and payment is necessary if the goal is to make the Company whole. The Administrative Law Judge found that interest on the transition obligation should be allowed to the same extent as the transition obligation itself. Finding No. 47. The Commission accepts and adopts that recommendation, believing it would be anomalous to allow recovery of interest on principal that has been disallowed.

### g. Twenty Year Amortization Period Established

Under FAS 106 Minnegasco can recognize the total transition obligation immediately, amortize it over the average remaining service period of active participants in its PBOP plan, or amortize it over 20 years. The Company proposed a 14-year amortization period, based on the remaining service period of active plan participants, for ratemaking purposes. (The Company stated it had not yet determined whether to amortize the transition obligation or recognize it immediately for financial reporting purposes.) The Department proposed a 16-year period, based on the weighted average remaining lives of active and inactive plan participants. The RUD-OAG recommended a 20 year amortization; the SRA recommended a 40-year period.

The Commission agrees with the Administrative Law Judge that a 20-year amortization period represents the best balance between shareholder and ratepayer interests. It eliminates the mismatch between the times costs are incurred and recognized within a reasonable time period and with moderate rate impact. The Financial Accounting Standards Board's acceptance of 20 year amortization periods is another indication of its basic reasonableness. The Commission accepts and adopts the Administrative Law Judge's finding (No. 43) and recommendation, and will establish a 20-year amortization period.

## B. Annual Adjustment for Gas Storage Carrying Costs

Minnegasco proposed an annual true-up of carrying costs associated with gas storage inventory. The true-up would compare the carrying costs on the level of stored gas inventory included in base rates with the carrying costs on its actual month-end levels of inventory for the year purchased from Natural Gas Pipeline of America (NGPL). The difference would be included in its annual gas cost reconciliation (PGA true-up). The carrying charge would be the overall authorized rate of return.

The Company argued that gas inventory carrying costs are a direct gas cost which should be trued-up through the PGA. Minnegasco stated that in the absence of a true-up, the Company will be at risk for under-recovery and ratepayers for over-recovery of these costs. Minnegasco argued that its position is consistent with Commission precedent on carrying costs on gas storage inventory.

The Department opposed the carrying-cost true-up proposed by Minnegasco. The Department contended that stored gas should be treated no differently than any other type of inventory used to provide utility service. Inventory is included in rate base and earns a return, thus allowing Minnegasco the opportunity to recover the associated carrying cost. The Department contended that there was no reason to guarantee the Company dollar for dollar recovery of this particular cost.

The ALJ recommended adopting Minnegasco's proposal to true-up carrying costs on gas storage inventory, finding it to be reasonable and to be consistent with past Commission orders.

The Commission rejects the Company's proposal to allow an annual true-up of carrying costs on stored gas inventory. The Commission finds no compelling reason to guarantee Minnegasco dollar for dollar recovery of this particular cost. Rather, stored gas inventory should be treated like all other types of inventory that are included in rate base and earn a return.

As noted by the parties, the Commission has granted variances to its PGA rules which allowed Minnegasco, and other gas companies, to recover carrying costs associated with recent gas storage contracts through the PGA. The Commission recognized that firm contract storage was a new service that was not built into the utility's base rates and was a benefit to ratepayers. Allowing recovery through the PGA would remove disincentives for the use of storage service by removing the risk of under-recovery. However, the Commission required that the issue of gas storage carrying charges be reviewed in the companies' next rate cases and specifically recognized that it may come to view recovery of carrying costs on a test year basis rather than through PGA filings.[7]

The Commission agrees with the Department that varying its PGA rules to allow Minnegasco, and other gas utilities, to include carrying charges on gas storage inventory until its next rate case was an equitable stop-gap approach for dealing with a new market environment. At that time, Minnegasco did not have storage costs related to the NGPL contract built into its base rates and thus would not have recovered carrying costs if the variance had not been granted. However, the situation has changed. In the Settlement, the parties agreed to include $18.2 million in rate base for Gas Stored Underground - Current. This reflects gas stored in Minnegasco's Waterville, Minnesota reservoir and gas storage purchased from NGPL. The Company will be allowed an opportunity to earn its overall rate of return on this amount, the same as with any other item included in rate base for the test year.

### C. Annual Adjustment for Taxes, Fees, and Permits

1991 amendments to Minn. Stat. § 216B.241 gave the Commission authority to allow utilities to adjust their rates for changes in taxes, fees, and permits under certain conditions. Minn. Stat. § 216B.241, subd. 2b. Recovery of expenses; taxes, provides in relevant part:

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[7] See, for example, In the Matter of a Petition from Northern States Power Company for a Variance to the Purchase Gas Charges, Automatic Adjustment Rule for Recovery of Carrying Costs Associated with Gas Storage Service, Docket No. G-002/M-90-630, ORDER GRANTING VARIANCE FOR ONE YEAR, April 4, 1991 and ORDER EXTENDING VARIANCE AND SETTING FILING REQUIREMENTS, December 10, 1991.

> . . . a utility may file annually, or the public utilities commission may require the utility to file, and the commission may approve, rate schedules containing provisions for the automatic adjustment of charges for utility service in direct relation to changes in the expenses of the utility for real and personal property taxes, fees, and permits, the amounts of which the utility cannot control. A public utility is eligible to file for adjustment . . . under this subdivision only if, in the year previous to the year in which it files for adjustment, it has spent or invested at least 1.75 percent of its gross revenues from provision of electric service and .6 percent of its gross revenues from provision of gas service for that year for energy conservation improvements under this section.

Under Minn. Stat. § 216B.241, subd. 1a, gas utilities are required to spend 0.5 percent of gross Minnesota operating revenues on energy conservation improvements. In order to be eligible for the adjustment for taxes, fees, and permits under subd. 2a, the gas utility must spend at least 0.6 percent.

Minnegasco proposed a Property Tax Adjustment Rider which would establish an annual adjustment for property taxes, fees, and permits, under this statute. Minnegasco proposed to file for the adjustment by March 31 of each year, to go into effect on June 1. The filing would compare the actual annual expenditures for real and personal property taxes, permits, and fees imposed by state and local governments to the amount collected in rates, based on allowed costs in the most recent rate case. The filing would also include documentation to show that the Company had met the required conservation spending levels.

Minnegasco argued that it is important to establish the adjustment rider now, before the Company has met the additional conservation spending levels. The rider will act as an incentive to encourage Minnegasco to spend more than the statutory minimum on conservation and avoid regulatory lag.

The Department opposed the Property Tax Adjustment Rider and argued that Minnegasco's request is premature. The Department noted that Minnegasco has not yet met the 0.6 percent conservation spending requirement. The Department argued that a more thorough review of the intent of the statute, the basis for authorizing such an adjustment, and the specifics of various terms need closer scrutiny to ensure consistent application. Therefore, if the statute is implemented it should be done through a rulemaking or some other generic proceeding.

The Department mentioned several policy questions that it believed should be addressed in a more generic manner. These included whether actual property tax expenses should be flowed through or just changes in tax rates; whether dollar for dollar recovery is appropriate; the effect of changes in jurisdictional allocations on tax expense; and how to define fees and permits. The Department also noted that if Minnegasco's merger with Midwest Gas is approved, its gross revenues and CIP expenses will change.

The ALJ recommended adopting the Company's proposed Property Tax Adjustment Rider. He stated that the concerns raised by the Department can be addressed in Minnegasco's compliance filing to be made when the Company achieves the required spending levels. The ALJ said that a rulemaking is not specifically required before the statute may be implemented and that a generic proceeding may not conclude before the Company reaches the required spending levels.

The Commission agrees with the Department that Minnegasco's proposal is premature and should be denied. The Company's CIP spending levels have not yet met the 0.6 percent threshold required to qualify for the automatic adjustment. If the proposed merger with Midwest Gas takes place, it may take some time to determine new annual revenue levels and to design and implement CIP programs at the required spending levels. There is therefore no clear need to act on the proposal now. Furthermore, establishing an automatic adjustment for the first time raises issues of law, policy, and implementation that were not thoroughly addressed in this proceeding. The Commission will therefore reject the Company's proposed Property Tax Adjustment Rider.

### D. Lost and Unaccounted for Gas

Lost and unaccounted for (LUF) gas is the difference between gas purchased and gas sold. Minnegasco proposed that LUF gas be included in the calculation of monthly PGA's. The Department recommended that the LUF gas be recovered by adjusting the volumes in the annual PGA trueup filing. Minnegasco agreed with the Department's approach. The Commission finds that this issue is uncontested and adjusting the volumes in the annual PGA trueup is a reasonable method to recover the cost for LUF gas. The Commission approves this method of recovery for LUF gas.

## XIII. DEMAND-SIDE MANAGEMENT (DSM) INCENTIVES AND CONSERVATION ISSUES

### A. Energy Conservation Improvement Plan

Minn. Stat. § 216B.16, subd. 1 (1992) requires utilities filing for a general rate change to include an energy conservation plan pursuant to Minn. Stat. § 216B.241 (1992). Minnegasco submitted its plan as part of its general rate case filing on July 2, 1992. Minnegasco's plan included information on the Company's strategy to expand its conservation activities into a comprehensive demand-side management plan.

The Department stated that Minnegasco's energy conservation plan complied with applicable statutes and contained the information requested by the Commission in the past. The Department recommended that the Commission accept the energy conservation plan filed by the Company.

The Commission believes the appropriate focus of a rate case conservation plan is on a utility's long-term conservation goals. Short-term projects and plans are currently reviewed by the Department in the Conservation Improvement Program (CIP) process under Minn. Stat. § 216B.241 (1992). The Commission finds that Minnegasco's energy conservation plan meets the requirements of the applicable statutes and addresses the long-term conservation goals of the Company. The Commission accepts the plan as filed.

**B. Carrying Charge on CIP Tracker Balances**

In a previous docket, the Commission authorized the establishment of a CIP tracker account for Minnegasco[8]. CIP expenditures and revenues are tracked in this account, until the balance is submitted for potential recovery or refund in the Company's next general rate case.

Minnegasco requested that it be allowed to implement a carrying charge on its CIP tracker balance in this rate case. The Company proposed that the carrying charge be applied at the Company's authorized rate of return on equity. The Company argued that setting the carrying charge at the return on equity rather than the overall return was consistent with the legislative mandate to encourage conservation.

The Department and the RUD-OAG agreed that Minnegasco should be allowed to implement a carrying charge on its CIP tracker balance. However, these parties recommended the carrying charge be set at the Company's overall rate of return, rather than the return on equity. The Department and RUD-OAG contended that a carrying charge at the overall rate of return adequately compensates the Company for the time value of money and that the carrying charge should not be used as a conservation incentive mechanism since it is tied only to spending, not to performance. The ALJ agreed with the Department and RUD-OAG positions. He noted that in past cases, the Commission has set the carrying charge at the overall rate of return, finding that it adequately compensates utilities for the time value of money.

The Commission agrees with all the parties and the ALJ that

[8] In the Matter of the Accounting for and Recovery of Conservation Expenses by Minnegasco, Inc., Docket No. G-008/CI-88-460, ORDER MODIFYING AND APPROVING COST RECOVERY PROPOSAL AND REQUIRING FILING, September 1, 1989.

Minnegasco should be allowed a carrying charge on its CIP tracker account. In other dockets, the Commission has consistently found that application of a carrying charge to the CIP tracker account, at the utility's authorized overall rate of return, is an equitable means of adjusting the actual level of CIP expenditures to the level projected in the utility's last rate case.[9] Allowing a carrying charge gives recognition to the time value of money to the utility and its ratepayers. If a utility spends more than is collected through the rates set in the most recent rate case, the utility is made whole. By the same token, ratepayers are made whole if they have "lent" money to the company through over-collection between rate cases. The Commission will apply the same reasoning to this docket and will allow Minnegasco to apply carrying charges to its CIP tracker account at the Company's authorized overall rate of return.

The Commission agrees with the Department, RUD-OAG, and ALJ that Minnegasco's proposal to set the carrying charge at the rate of return on equity should be rejected. As stated above, setting the carrying charge at the overall rate of return adequately recognizes the time value of money and meets the objective of making the Company and ratepayers whole for any under- or over-collection of actual CIP costs. Any further encouragement for utility investment in conservation is better left to a well-designed demand-side management (DSM) financial incentive mechanism. DSM financial incentive proposals are discussed in a subsequent section of this Order.

### C. Conservation Cost Recovery Charge

A conservation cost recovery charge (CCRC) is used by most utilities to track recovery of CIP-related costs. The CCRC is calculated by dividing allowed test-year CIP expenses by allowed test-year sales units; the result represents the revenue per Mcf that will be collected in rates related to test year CIP costs. These revenues are booked to the CIP tracker. The difference between the revenues booked and the actual expenses incurred will determine the CIP tracker balance.

In response to staff questions at evidentiary hearings, Department witness Kosowski stated that the proper CCRC to use in calculating the CIP-related revenues in this case was $0.02894/Mcf. Minnegasco agreed with this calculation. The ALJ found it to be reasonable.

The Commission notes that the CCRC can be derived from numbers agreed to in the Settlement. Test year CIP expenses of $3,544,833 are divided by test year gas sales volumes of

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[9]See, for example, <u>In the Matter of the Proposal of Northern States Power Company's Gas Utility for a Demand-Side Management Incentive Mechanism</u>, Docket No. G-002/M-92-516, ORDER APPROVING DEMAND-SIDE MANAGEMENT FINANCIAL INCENTIVE PLAN WITH MODIFICATIONS AND REQUIRING FURTHER FILINGS, January 7, 1993.

122,475,162 Mcf, resulting in the CCRC of $0.02894/Mcf noted by the parties. Therefore, the Commission finds that a CCRC of $0.02894 is reasonable and should be used by the Company.

## D. Demand-Side Management Financial Incentive

### 1. The Company's Request

On October 18, 1991, the Commission issued its ORDER REQUIRING GAS UTILITIES TO FILE FINANCIAL INCENTIVE PROPOSALS in Docket No. G-999/CI-91-188, In the Matter of a Summary Investigation into Financial Incentives for Encouraging Demand-Side Resource Options for Minnesota Gas Utilities. In that Order, the Commission required all natural gas utilities (except Midwest Gas, which was already implementing a financial incentive pilot program) to file DSM financial incentive proposals. Minnegasco filed its proposal as part of this rate case.

For its DSM financial incentive, Minnegasco proposed to recover 100 percent of lost margins due to conservation from direct impact programs. The Company planned to measure lost margins by comparing pre- and post-participation usage for a participant and comparison group. Minnegasco proposed to book lost margins to its tracker account on a monthly basis.

The Company stated that the removal of disincentives was the Company's highest priority at this time. Minnegasco argued that the Commission has previously found that 100 percent recovery of lost margins is adequately tied to performance and complies with statutory criteria. In rebuttal testimony, Minnegasco stated that if the Commission were to find a bonus incentive desirable, the Company could accept adding a 10 percent bonus on lost margins if the Company exceeded its energy savings goals.

Minnegasco opposed the performance-linked recovery of lost margins proposed by the Department and RUD-OAG. The Company stated that both proposals were unreasonable because the small "carrot" (amount of potential bonus recovery) would be quickly offset by the magnitude of the "stick" (less than full recovery of lost margins if 100 percent of goals were not met). Minnegasco argued that a number of factors beyond the Company's control could affect its ability to meet its CIP goals, and thus its ability to recover lost margins.

### 2. Position of the Parties; Recommendation of the ALJ

The Department and the RUD-OAG both opposed Minnegasco's DSM financial incentive mechanism and instead proposed plans that would tie lost margin recovery to the achievement of energy savings goals. These parties argued that Minnegasco would be financially indifferent as to whether it achieves more or less than its projected energy savings, because it will receive 100 percent of the margin for each unit of gas sold or each unit of gas saved.

The Department proposed to tie lost margin recovery to savings goals for direct impact programs on a project by project basis. The Department incentive mechanism would allow recovery of 110 percent of lost margins if energy savings goals are exceeded; 100 percent recovery if the goals are met; 75 percent recovery if 75 to 100 percent of goals are achieved; 50 percent recovery if 35 to 75 percent of goals are met; and no recovery if less than 35 percent of goals are achieved.

The RUD-OAG incentive proposal would require at least 50 percent of program savings goals to be achieved before any lost margin recovery was allowed. If 50 percent or more of goals are achieved, the proposal would allow lost margin recovery as a percentage of actual savings compared to projected savings. For example, if Minnegasco achieved 60 percent of its projected goal, the Company would receive 60 percent of its lost margins. Recovery would be capped at 1.2 times savings, allowing a maximum bonus of 20 percent of lost margins.

The Department and the RUD-OAG recommended approval of Minnegasco's method for measuring lost margins, with the modification that CIP participants be excluded from the comparison group to provide a greater accuracy of measurement.

The Department and RUD-OAG argued that lost margins should be booked to the tracker annually, after the Commission has approved the energy savings achieved. These parties recommended that Minnegasco file its calculation of lost margins and incentives to be included in the tracker on November 1 of the succeeding CIP year, beginning in 1994. The RUD-OAG also recommended an initial compliance filing within 60 days of this Order which would list all projects the Company believes qualify for the incentive and the associated energy savings goals.

The Department recommended that the program be limited to a two year pilot project, as the Commission has done for all other DSM incentive programs.

The ALJ recommended approving Minnegasco's DSM incentive proposal to recover 100 percent of its lost margins from direct impact programs. He agreed with the RUD-OAG that CIP participants should be excluded from the comparison group for measuring lost margins. The ALJ agreed with the Department and OAG that lost margins should be booked annually, rather than monthly. He found that annual compliance filings were appropriate.

### 3. Commission Analysis

Minn. Stat. §216B.16, subd. 6c (1992) sets out the following factors the Commission is to consider when evaluating financial incentives:

(1) whether the plan is likely to increase utility investment in cost-effective energy conservation;

(2) whether the plan is compatible with the interest of utility ratepayers and other interested parties;

(3) whether the plan links the incentive to the utility's performance in achieving cost-effective conservation; and

(4) whether the plan is in conflict with other provisions of the statute.

The Commission put forth the following principles for developing proposed incentive plans in its October 18, 1991 Order requiring gas utilities to file DSM incentive proposals:

> Utilities should tailor their incentive plans to meet their own individual needs. . . .
>
> . . . The Commission . . . expects financial incentives to be tied to cost effectiveness.
>
> . . . financial incentives should be tied to achieving objective demand side goals. Awarding financial incentives for spending money without results would serve no useful purpose and would undermine the legislative goal of achieving significant reductions in Minnesota energy use.

The Commission has approved several different types of DSM incentive mechanisms for Minnesota utilities, including 100 percent lost margin recovery, 100 percent lost margin recovery with a bonus, and incentives which vary the amount of lost margin recovery based on performance. There are a variety of potential DSM incentive mechanisms which can achieve the goals set out in statute and the principles outlined by the Commission.

The Commission notes that Minnegasco has a large CIP program with a relatively wide variety of projects. The Company has considerable experience in successfully running these programs, starting with its participation as one of the utilities in the pilot utility conservation improvement program (PUCIP) which started in 1980. The Commission finds that it would be valuable to look at the effect of a positive financial incentive mechanism, rather than simply removing the obstacle of lost margins, for a utility such as Minnegasco. The Commission finds that either the Department or the RUD-OAG proposal would provide a positive financial incentive to Minnegasco, since the Company has the opportunity to recover more than 100 percent of its lost margins.

The Commission will adopt the RUD-OAG proposal. This financial incentive mechanism employs a continuous sliding scale recovery, thereby providing an increased incentive for achieving energy savings at every step. The Commission finds that the RUD-OAG proposal provides an appropriate level of bonuses and penalties; the Company must achieve at least 50 percent of its energy savings goals before it is eligible for a bonus, and has the potential to receive up to a 20 percent bonus for exceeding its goals. The threshold for achieving recovery and the potential bonus are both higher than under the Department proposal.

The Commission rejects Minnegasco's argument that it is unreasonable to require that a performance threshold be met before lost margin recovery is allowed. In prior orders for other companies, the Commission has found that it is just as reasonable to penalize substandard conservation performance as it is to reward satisfactory or outstanding performance.[10]

Minnegasco proposed to measure lost margins by comparing the consumption levels of CIP participants with the consumption levels of a comparison group of similarly situated ratepayers. The Commission agrees with the RUD-OAG that this is generally a workable approach, but that it should be refined to exclude CIP participants from the comparison group, for greater accuracy.

The Commission will require the Company to file a calculation of lost margins for a given CIP year by November 1 of the succeeding year, beginning with November 1994, as recommended by the parties. The Commission will also adopt the RUD-OAG recommendation to require an initial compliance filing that lists all projects the Company believes qualify for the incentive and the associated energy savings goals. This will help ensure that all parties understand and agree on the specific parameters of the program before proceeding.

The Commission has structured all current DSM financial incentive programs as two-year pilot projects. The Commission will do so for Minnegasco also. This structure allows the Commission to review the program in a timely manner and determine if incentive plans are working as intended, need modification, or whether the entire issue should be revisited.

## XIV. OVERALL FINANCIAL SUMMARIES

### A. Rate Base Summary

Based on the above findings, the Commission concludes that the appropriate rate base for the test year is $275,055,140 as shown below:

[10] See, In the Matter of the Proposal of Otter Tail Power Company for a Demand-Side Management Financial Incentive, Docket No. E-017/M-91-457, ORDER ESTABLISHING DEMAND SIDE MANAGEMENT INCENTIVE PILOT PROJECT AND REQUIRING FURTHER FILINGS, March 12, 1992.

| | |
|---|---|
| UTILITY PLANT IN SERVICE | $524,943,057 |
| Accumulated Depreciation and Amortization | (236,253,545) |
| | 288,689,512 |
| Gas stored underground: | |
| Current | 18,214,000 |
| Non-current | 997,000 |
| Accumulated Deferred Income Taxes | (28,733,000) |
| Materials and Supplies | 3,049,000 |
| Cash Working Capital | (6,493,737) |
| Deferred Debits and Credits | (4,235,635) |
| Other Working Capital | 3,568,000 |
| TOTAL RATE BASE | $275,055,140 |

**B. Operating Income Statement Summary**

Based on the above findings, the Commission concludes that the appropriate Minnesota jurisdictional operating income for the test year under present rates is $21,206,518 as shown below:

| | |
|---|---|
| OPERATING REVENUES: | |
| Gas Sales | $448,887,256 |
| Other Revenues | 2,219,000 |
| Total Operating Revenues | 451,106,256 |
| OPERATING EXPENSES: | |
| Cost of Gas | 305,567,255 |
| Production and Maintenance | 13,412,723 |
| Distribution and Utilization | 14,257,783 |
| Depreciation and Amortization | 23,341,397 |
| Customer Service and Information | 5,160,029 |
| Sales and Customer Accounts | 16,025,114 |
| Administrative and General | 21,782,555 |
| Other Expense | 895,000 |
| Taxes Other Than Income | 22,234,000 |
| Federal and State Income Taxes | 6,650,588 |
| Total Operating Expenses | 429,326,444 |
| TOTAL OPERATING INCOME | $21,779,812 |

**C. Gross Revenue Deficiency**

Based on the Commission findings and conclusions, the Minnesota jurisdictional revenue deficiency for the test year is as shown below:

| | |
|---|---|
| Rate Base | $275,055,140 |
| Rate of Return | 10.41 % |
| Required Operating Income | $28,633,240 |
| Operating Income | 21,779,812 |
| Income Deficiency | $6,853,428 |
| Revenue Conversion Factor | 1.67977 |
| Revenue Deficiency | $11,512,000 |

## XV. REMAINING CONTESTED RATE DESIGN ISSUES

### A. Revenue Apportionment to the Customer Classes

MEC, a party to these proceedings but a non-signatory of the Settlement, challenged the revenue allocation among the customer classes proposed in the Settlement. In its consideration of the Settlement, the Commission considered MEC's claim that the revenue allocation was unreasonable. The Commission rejected MEC's claim and found that the Settlement's revenue allocation was reasonable, pursuant to the following analysis.

In the Amended Offer of Partial Settlement, the parties proposed the following rate increases and decreases:

| | |
|---|---|
| Residential | + 7.30 percent |
| Commercial & Industrial Sales | + 2.63 percent |
| Large-Volume Commercial and Industrial | + 0.00 percent |
| Small-Volume Dual Fuel | + 7.90 percent |
| Large-Volume Dual Fuel | + 0.00 percent |

MEC was not content that rates for Large-Volume customers remain unchanged while rates for all the other classes increased. MEC proposed that the rates for Large-Volume customers actually decrease. Under MEC's proposal, rates for the Residential and small Commercial and Industrial customers would increase and rates for all of the other customer classes would decrease. MEC proposed rate increases and decreases which it modified in surrebuttal testimony to the following:

| | |
|---|---|
| Residential | + 8.9 percent |
| small Commercial & Industrial Sales | + 8.9 percent |
| Commercial & Industrial Sales | - 5.4 percent |
| Large-Volume Commercial and Industrial | - 3.52 percent |
| Small-Volume Dual Fuel | - 3.28 percent |
| Large-Volume Dual Fuel | - 6.76 percent |

MEC argued that the Settlement's revenue allocation would perpetuate what it characterized as the subsidization of residential and small C&I customers by the Large Volume C&I and Dual Fuel customers. MEC also argued that an 8.9 percent rate increase for Residential customers would not be large enough to cause "rate shock" and would move the Company more rapidly toward cost-based rates.

MEC failed to persuade the Commission that the Settlement's revenue allocations were outside the range of acceptable regulatory practice so that the resulting rates are unfair and unreasonable. Judgements as to what constitutes rate shock and how far and how rapidly the Commission should move toward cost-based rates are uniquely legislative decisions left to the Commission's sound discretion. In addition to cost, there are other critical rate design considerations. As the Minnesota Supreme Court has stated:

> Once revenue requirements have been determined, it remains to decide how, and from whom, the additional revenue is to be obtained. It is at this point that many countervailing considerations come into play. The Commission must balance factors such as cost of service, ability to pay, tax consequences, and ability to pass on increases in order to achieve a fair and reasonable allocation of the increase among the customer classes. St. Paul Area Chamber of Commerce vs. Minnesota Public Service Commission, 251 N.W. 2d 350 (1977).

The Commission has recognized that moving prices toward cost is a reasonable policy. The Commission generally supports the movement toward cost-based pricing, but recognizes that there are other non-cost factors that are equally important. For example, the Commission has stated:

> Avoiding rate shock is a primary ratemaking goal, because sudden, drastic increases in energy costs can be burdensome for residential and non-residential ratepayers alike. Avoiding rate shock is particularly important for residential ratepayers, however, because increases in the cost of basic needs can cause hardship for customers on low or fixed incomes. In the Matter of the Application of Midwest Gas, a Division of Iowa Public Service Company, for Authority to Change Its Schedule of Gas Rates for Retail Customers within the State of Minnesota, Docket No. G-010/GR-90-678, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER (July 12, 1991), p. 35.

Furthermore, the Commission recognizes that cost studies and their underlying economic theories necessarily involve some imprecision. This imprecision adds to the Commission's unwillingness to place the entire rate increase on residential customers and small businesses, as MEC proposed. Given these considerations, the Commission finds that the revenue allocations proposed in the Settlement are reasonable.

### B. Residential Customer Charge

#### 1. Historical and Factual Background

The residential customer charge is the fixed monthly rate residential customers pay for being hooked up to Minnegasco's system. Minnegasco proposed raising the customer charge for residential customers to $5.00 from $3.00 per month. The Department proposed an increase to $5.50 and the RUD-OAG proposed leaving the customer charge at $3.00. The parties reached no agreement on this issue and it was litigated in the contested case proceeding. (Customer charges for the other customer classes were agreed to by the parties to the Settlement.)

In setting the level of a customer charge, parties generally analyze the fixed cost of providing service to the customer class. Normally the monthly cost is determined through a Class Cost of Service Study (CCOSS) and is apportioned between the fixed monthly customer charge and the variable commodity charge. The proportional levels of these two factors have important effects on such issues as energy consumption, rate and revenue stability, and equity in and among customer classes.

In this rate case, the parties to the Settlement adopted the Department's Class Cost of Service Study (CCOSS) for the purpose of setting rates. This study demonstrated fixed residential customer costs of $14.62 per month. Minnegasco did not believe there was a significant enough difference between the numbers in its CCOSS and the Department's to contest the Department's study. Both parties agreed that rate shock would occur if rates for the residential class were exactly aligned with the cost of service.

**2. Positions of the Parties; Recommendation of the ALJ**

Minnegasco - The Company proposed to increase the residential customer charge from $3.00 to $5.00. The Company argued that a $2.00 increase was a reasonable move towards the $14.62 stipulated class cost of service in this case. The Company argued that a $5.00 customer charge would only recover approximately 35 percent of its embedded customer costs.

Minnegasco argued that a higher customer charge would give it greater financial stability because the fixed monthly charge would provide it with additional revenue independent of weather conditions and customer gas usage.

Minnegasco also argued that moderating the increase to $5.00 instead of going right to full cost, i.e. $14.62, would make the increase more acceptable to customers and maintain a reasonable degree of continuity with the Company's historical rates.

The Department - The Department proposed to increase the customer charge to $5.50. The Department proposed a higher increase than the Company because it believes the Company's proposal does not move far enough in the direction of cost based rates. The Department also argued that a higher customer charge would promote economically efficient use of gas because rates would better represent cost and would allow ratepayer to make better informed decisions about the cost of the energy they consume.

The Department agreed that revenue stability would be improved and Minnegasco would have a better chance of recovering its revenue requirement.

The Department argued that setting the customer charge closer to cost would reduce the potential for intra-class cross-subsidization of fixed costs between high use and low use customers.

RUD-OAG - RUD-OAG proposed leaving the customer charge at $3.00 and allowing the Company to collect the entire class revenue deficiency through an increase to the energy charge. RUD-OAG argued that putting the entire increase into the energy charge would encourage energy conservation because energy consumption is sensitive to price.

The RUD-OAG relied heavily upon Minn. Stat. § 216B.03 (1992) to support its argument. Among other things, that statute states: "To the maximum reasonable extent, the Commission shall set rates to encourage energy conservation...." The RUD-OAG argued that increasing the proportion of fixed costs in the customer charge (and thereby decreasing the proportion in variable charges, which are tied to energy consumption) would diminish consumer incentives to conserve energy.

According to the RUD-OAG, analysis of a rate design proposal demands a balancing between the need for revenue stability and conservation goals. The RUD-OAG also argued that if a reliance on variable charges caused under-recovery in years with above-normal temperatures, this would eventually be balanced by over-recovery in years of below-normal temperatures.

RUD-OAG argued that maintaining the existing customer charge would give the Company a reasonable opportunity to meet its revenue requirement with the only difference between it and the Company's proposal being that more of the revenue requirement would be collected through the energy charge.

RUD-OAG believes its proposal would allow for a greater amount of historical continuity with prior rates and would promote a greater degree of customer acceptance of those rates because it would allow customers more control over their bills due to more of the cost being recovered through a variable charge.

The ALJ's Recommendation - The ALJ recommended adopting the Company's proposal for a $5.00 customer charge. The ALJ found it appropriate to move in the direction of cost based rates and believes that a $2.00 increase would be an appropriate step in that direction.

The ALJ concluded that a $5.00 customer charge would improve the Company's revenue stability because it would allow the Company to recover more of its fixed costs on a steady basis and would reduce the Company's risk of under-recovering its revenue requirement in warmer than normal weather.

The ALJ recommended the Company's proposal over the Department's because he believes a $5.00 rather than a $5.50 customer charge would be more likely to gain customer acceptance and is more in line with historical rates.

### 3. Commission Analysis

A rate design decision requires exercise of the Commission's legislative function. The Commission must weigh the facts in evidence to determine if the rate design proposed by the utility is justified and will result in just and reasonable rates.

The Commission agrees with the ALJ that Minnegasco's proposed increase to the residential customer charge should be approved. This position is reasonable and equitable, is not inconsistent with the facts in evidence, and is in line with prior Commission decisions.

In the 1992 Interstate rate case[11] the Commission adopted the Company's proposal for an increase to the residential customer charge, against opposition from the RUD-OAG. In that Order the Commission stated:

> The Commission notes that customer charges are substantially below cost for all classes of customers. .... As a result, the Commission believes an active step should be taken in this case to move these charges closer to cost. Moving prices toward cost is a reasonable policy which sends the proper price signals, spreads costs in an equitable fashion, and tends to eliminate intraclass cost subsidization.
>
> Order at p. 44.

The Commission notes that in this case the present monthly residential customer charge is $3.00 and fixed cost is approximately $14.62. A move toward cost is warranted in this case and will promote the goals cited in the Interstate Order.

The Commission is aware of its statutory mandate to set rates to encourage energy conservation "[t]o the maximum reasonable extent." Minn. Stat. § 216B.03 (1992). Even at $5.00, the customer charge will not adversely affect the Commission's conservation goals because a substantial part of the Company's fixed costs will remain in the variable charge. This will provide customers with an incentive to conserve energy. Moreover, acting in its legislative mode, the Commission views any rate design proposal in its full context to determine what is reasonable in the context of the case. The Commission must balance such factors as fairness to ratepayer, conservation goals, revenue and rate stability when making a rate design decision. The Commission is also aware that the statute instructs the Commission to resolve all questions regarding reasonableness in favor of the consumer. Minn. Stat. § 216B.03 (1992). Having weighed the factors in this case, the Commission

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[11] In the Matter of the Application of Interstate Power Company for Authority to Increase Its Rates for Electric Service in the State of Minnesota, Docket No. E-011/GR-91-605, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER (June 12, 1992).

finds that Minnegasco's proposed increase in the residential customer charge will result in just and reasonable rates. The Commission will approve Minnegasco's increase.

### C. Energy Charge for the Firm Customer Classes

At issue was how the "energy charge" for Residential and C&I firm customer classes would be designed.

#### 1. Historical and Factual Background

In this rate case, the term energy charge is used to describe the combination of the unit margin (also called the commodity-margin or the non-gas unit margin) and the per unit demand costs that are included in the base cost of gas and the monthly purchased gas adjustments (PGAs). This explanation is necessary because it is more common to use the term energy charge to refer to the entire variable cost of energy including the commodity cost of gas.

In its current rates, Minnegasco recovers its unit margin and its demand costs at a constant rate per unit of gas over the entire 12 months of the year. The only seasonal variability in Minnegasco's rates are due to seasonal differences in the commodity cost of gas and the amount of gas its customers buy during one part of the year versus another.

#### 2. Proposals of the Parties; Recommendation of the ALJ

Minnegasco - Minnegasco proposed what it termed a "balanced energy charge." The Company proposed to recover its pipeline demand costs on a seasonal basis at the same time those costs are incurred, i.e. higher PGA demand charges in winter, during the five month heating season from November through March, when it uses more firm pipeline capacity, and lower PGA demand charges in the summer, during the seven month non-heating season, when it uses less pipeline capacity.

To balance the seasonal fluctuations that would be caused by recovering its pipeline demand costs on a seasonal basis, however, Minnegasco also proposed to vary the non-gas unit (commodity) margin on a seasonal basis *in the opposite direction* from PGA demand costs. During the five month winter heating season when demand costs are higher the unit margin would be reduced and in the summer when demand costs are lower the unit margin would be increased. This arrangement would offset the difference between heating season and non-heating season demand costs with a seasonal unit margin and keep the total per unit energy charge, excluding the commodity cost of gas, constant.

Minnegasco argued for a balanced energy charge because it would provide Minnegasco with a more stable revenue stream and a better opportunity to recover its fixed costs under abnormal weather conditions because it would reduce the Company's dependence on a high level of winter throughput. Minnegasco also argued that under its proposal the demand component of the balanced rate would be more closely based on cost.

The Department - The Department proposed rates fully responsive to the seasonal fluctuation of pipeline demand costs. The Department stated that the Company's rates should reflect pipeline capacity costs at the time those costs are incurred. The Department argued that fully seasonal rates would send more appropriate price signals to Minnegasco's customers when the Company's system is at its peak. The Department argued that seasonal rates have the potential for improving Minnegasco's system load factor, lowering system-wide peak demand costs and would better promote energy conservation.

RUD-OAG - The RUD-OAG proposed making no design changes to the unit margin and in the way PGA demand costs are recovered. The RUD-OAG recommended maintaining level demand charges and margins throughout the entire year without any seasonal variation. The RUD-OAG argued that the Company had offered no cost justification for its balanced energy charge proposal except to maintain level year-round rates which already exist.

The RUD-OAG also objected to the Department's proposal on the grounds that it would put too much of a burden on customers during the winter and cause rate shock. The RUD-OAG argued that the benefits that would result from increased conservation due to higher winter bills must be carefully evaluated against the additional financial burden higher winter rates would place on customers during the heating season.

ALJ - The ALJ recommended adopting the Department's proposal for seasonal, time-of-use rates. The ALJ believes the Department's proposal would encourage customers to use and conserve natural gas efficiently, while attempting to keep overall cost recovery from the class constant.

The ALJ found that the Department's seasonal rate proposal sends the best price signals to firm customers by increasing the demand rate they pay during the winter season and lowering it in the summer when gas is cheaper. The ALJ also found that the Department's seasonal rates reflect actual cost by keeping the unit margin constant throughout the year. Any rate shock on customer bills during the winter is balanced by cheaper bills during the summer, and leads to the same amount of annual revenue.

The ALJ also found that the availability of the Company's budget plan mitigates any hardship that could result from higher winter bills. The ALJ believes that recording on budget plan customers' bills the actual rate charged such customers during the winter sends appropriate price signals.

The ALJ also found that the Company failed to demonstrate a benefit to ratepayers from its balanced recovery proposal beyond maintaining level rates throughout the year, a result which is achieved already under the current rate structure and the Company's budget plan.

### 3. Commission Analysis

The Commission finds Minnegasco's proposal for a balanced energy charge is unacceptable. It does not send accurate price signals, does not offer any benefit to ratepayers above and beyond what exists under current rates, and does not appear practical from a regulatory standpoint.

The Commission is intrigued by the Department's seasonal rate proposal. The Commission is interested in exploring the potential benefits to be achieved through the implementation of seasonal rates that send accurate price signals to consumers. These benefits may be in the form of increased energy conservation and/or lower rates because of improvements in the efficient utilization of Minnegasco's distribution system during periods of peak demand.

However, the Commission finds that the Department's proposal in this case leaves too many questions unanswered about how seasonal rates would transmit price signals to customers and whether those signals would have enough impact on customers to be worth the change in rate design. The Commission is also concerned about the regulatory feasibility of changing rates outside of a rate case or a miscellaneous tariff filing and believes this issue needs to be explored more carefully in any future request for implementation of a seasonal rate.

After careful consideration of the three rate design proposals the Commission finds that it is appropriate to leave the design unchanged as recommended by the RUD-OAG. The Commission will not require Minnegasco to develop and propose a seasonal rate at this time because the Company's existing rate design already sends a price signal during the heating season based on seasonal commodity prices and customer gas usage. However, the Commission would entertain a more fully developed proposal in the future.

## D. Three-Part Rate for Large-Volume Commercial and Industrial (C&I) Customers

The Department recommended that the Company design and propose a three-part rate for its Large-Volume C&I customer class. The Department argued that a three-part rate instead of the current two-part rate would be a more efficient pricing scheme because it would separate fixed costs, demand costs, and commodity costs on the customer's bill and would send a clear price signal to customers about the cost of using natural gas.

The Department recommended allowing the Company one year from the date of the final order in this rate case to design and propose a three-part rate for these customers in a miscellaneous tariff filing. The Department believed a year was needed because implementation would require each of these customers to install expensive tele-metering equipment at their place of business.

Minnegasco did not rebut the Department's position on the need for a three-part rate for this customer class and the ALJ did not make a recommendation on this issue. (All rate design issues for the Large-Volume C&I customer class were settled except for this one and the design of the energy charge.)

The Commission finds the Department's recommendation may warrant further consideration but will not require Minnegasco to make a proposal in a separate miscellaneous tariff filing. Rather, the Commission finds it would be a more efficient use of parties' and the Commission's time for Minnegasco to develop a three-part rate for its Large-Volume C&I customers as an alternative for parties to consider in its next rate case.

### E. Additional Rate Classes for Small-Volume Dual Fuel Customers

The Department recommended that the Company examine whether there is a need for additional customer classes and tariffs for smaller, more homogenous groups of Small-Volume Dual Fuel (interruptible) customers. All rate design issues for the Small-Volume Dual Fuel customer class except this one were settled. The Department made its recommendation in response to the Company's proposal to offer this customer class a two-tier declining block rate.

Minnegasco did not rebut the Department's recommendation. The ALJ recommended that the Company prepare a study of Dual-Fuel customers for submission prior to its next rate case, analyzing appropriate subclasses or customer groupings.

The Commission finds that a separate study of this issue is not necessary at this time and rejects the Department's recommendation without prejudice. The Commission notes that the Department recommended this study in response to the Company's original proposal to offer a declining block rate. Subsequently, the parties agreed to a single, flat-rate unit margin in the Settlement. The Commission finds that any party may make a specific proposal for additional interruptible customer classes when the Company files its next rate case.

### F. Process Interruptible Sales Service Rider

Under Minnegasco's original proposal, process gas users with no alternative fuel capability would be eligible for the Small-Volume Dual Fuel rate if they were willing to accept curtailment upon notice from the Company. Minnegasco identified three other conditions that would have to be met for a customer to qualify for this rate: a signed contract accepting the curtailment provisions of the service, designation of three individuals that can be notified in the event of a curtailment and installation of tele-metering equipment at the customer's expense.

The Department agreed that an interruptible rate would be appropriate for these customers under these conditions. However, the Department did not agree that eligibility for the rate should be limited only to process gas users. The Department recommended making the rate available to all customers with these load characteristics. Minnegasco amended its proposal to incorporate the Department's recommendation.

The ALJ recommended approving Minnegasco's amended proposal. The ALJ found that the Process Interruptible Sales Service Rider would improve the Company's overall load factor to the benefit of all customers.

The Commission agrees with the Department and believes rates should be based on load characteristics and conditions of service rather than on what the gas is going to be used for. Therefore, the Commission accepts and adopts the ALJ's recommendation and approves the Company's amended Process Interruptible Sales Service Rider.

### G. Main and Service Line Extensions

Minnegasco proposed an increase to the footage allowances for main and service line extensions provided to new customers without charge and decreases in the per foot charges for extensions in excess of the footage allowances. The Department agreed that the proposed changes were appropriate and would reflect Minnegasco's average cost for new extensions.

The Department also recommended that the Company add an economic feasibility formula to its tariff to clarify what criteria it uses to evaluate whether it needs to collect an extension charge, a contribution-in-aid-of-construction or a customer-advance-for-construction. The Department also suggested modifications that would require the Company to collect an advance-for-construction and make refunds under certain conditions instead of allowing the Company complete discretion over these decisions.

Minnegasco agreed to the Department's recommendations and proposed to incorporate them into its tariff when it makes its compliance filing. The ALJ found this tariff proposal to have merit.

The Commission accepts and adopts the ALJ's recommendation and approves the new extension footage allowances and excess footage charges. The Commission will require the Company to submit an economic feasibly formula and revised tariff language in its Compliance Filing as recommended by the Department.

### H. Late Payment Policy for Commercial and Industrial (C&I) Customers

Minnegasco proposed to extend the due date for C&I customers to pay their gas bills by 10 days, an increase from 15 to 25 days. This increase would give C&I customers the same amount of time as

Residential customers to pay their bill before a late charge is assessed. The Department agreed that this would be a fair policy for all customers.

The ALJ did not make a specific recommendation on the late payment policy for C&I customers.

The Commission finds that the Company's proposal is reasonable and approves the extension of the late payment time period for C&I customers.

### I. Therm Billing

Minnegasco proposed to bill all of its customers in therms because it would ensure that all of its customers receive an equivalent amount of energy for every unit billed. (A therm is a standardized unit of energy commonly used in the gas industry and is equivalent to 100,000 Btus.) Minnegasco proposed to replace its current Btu pressure adjustment with a therm factor adjustment.

The Department agreed this would be an appropriate change because it would ensure that all customers are billed using equivalent units of energy and that it would not have any impact on revenue. The ALJ recommended allowing Minnegasco to adopt therm billing.

The Commission accepts and adopts the ALJ's recommendation and approves the Company's proposal to bill all of its customers in therms instead of Btu-adjusted Ccfs.

### J. Miscellaneous Tariff Book Organizational Changes

Minnegasco proposed several language and organizational changes to its tariff book that make the tariffs easier to use. None of the parties objected to these changes and the ALJ found they were reasonable and appropriate. The ALJ recommended that they be approved.

The Commission accepts and adopts the ALJ's recommendation and approves the Company's miscellaneous tariff book changes.

### K. Continuity of Service

Minnegasco proposed to replace its tariff entitled Maintenance and Responsibility with a substitute tariff entitled Continuity of Service. Minnegasco's proposal would limit its risk for service interruptions and shifts some of that risk onto its customers. Minnegasco argued that NSP has been permitted to use language in its tariff that is practically identical to what Minnegasco has proposed.[12]

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[12] Staff notes that NSP-Electric's tariff on Continuity of Service was a part of NSP's tariffs prior to electric and gas utilities becoming rate regulated in Minnesota in 1974. The

The Department argued against changing any of the existing tariff language because it believes the proposed language would unreasonably limit the Company's liability. The Department argued that the existing tariff language adequately addresses the Company's responsibility for providing an adequate and continuous supply of gas to its customers.

The ALJ found that the Company's proposed language provides sufficient protection for customers and puts a reasonable limit on the Company's liability. The ALJ recommended adopting the Company's proposal.

The Commission is not completely persuaded by any of the arguments in favor or against maintaining the current standard of negligence and liability found in the Company's tariff and believes that further development and examination of the issues involved will be required. However, the Commission finds merit in the Company's proposal to limit its liability against claims resulting from loss of profits and other consequential damages due to service related problems because these kinds of losses are typically covered by a C&I or Dual-Fuel customer's own insurance.

Therefore, the Commission will maintain the current tariff language but permit the Company to add the following sentence:

> Minnegasco will not be liable for any loss of profits or other consequential damages resulting from the use of service or any interruption or disturbance of service.

**L. Right to Remove a Gas Meter**

Minnegasco proposed to be allowed to remove the gas meter from a customer's premise if the customer has not used any gas for at least 12 months. Minnegasco argued that the customer charge alone does not cover the cost of keeping an idle meter in place.

The Department suggested modifying the Company's proposal to require Minnegasco to give its customers advance notice of its intention to remove a meter at a customer's premise and a requirement that the meters selected for removal are chosen on a non-discriminatory basis.

The ALJ recommended acceptance of the Company's proposal with the modifications suggested by the Department. The ALJ found that with the Department's modifications the proposal was reasonable.

The Commission agrees with the ALJ and will approve the Company's amended tariff entitled Minnegasco's Right to Remove a Gas Meter.

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propriety of this kind of language has not come before the Commission for deliberation prior to it becoming an issue in this docket.

### M. Customer Deposits

The Department proposed making it mandatory for Minnegasco to collect a deposit from all new and existing customers. The Department was concerned that allowing Minnegasco discretion over whether it collects a deposit from customers would make it too easy for Minnegasco to administer its customer deposit program in an unfair or discriminatory manner.

The Company objected because it currently does not collect a deposit from any of its customers. The Company argued that a deposit program would cost more to administer than it would save by reducing unpaid bills. The Company also argued that a mandatory deposit program would be inconsistent with the Commission's Rules which allow a utility to collect a deposit only if the customer has an unsatisfactory credit or service record as determined using the criteria set forth in Minn. Rules parts 7820.4100-.4700.

The ALJ recommended accepting the Company's tariff language as originally proposed because it is consistent with the Commission's rules on customer deposits and adequately describes the Company's customer deposit policy.

The Commission agrees with the ALJ's recommendation and approves the Company's tariff as originally proposed. In light of Minnegasco's current practice of charging no deposit to any customer, the expense to Minnegasco and detriment to all customers of requiring the Company to collect a deposit from all customers clearly outweighs the value of guarding against potential discriminatory application of some future deposit requirement.

### N. No Charge Service

The Department recommended changing the name of the Company's No Charge Service tariff to No Surcharge Service. This tariff describes some of the services Minnegasco provides to customers without any additional charge including emergency leak inspections, maintenance of meters, pressure regulator and service lines and meter turn-ons for new customers. The Company did not object to the Department's proposal and the ALJ recommended adopting it.

The Commission finds the Department's recommendation is reasonable and approves the new title for this tariff.

### O. New Area Surcharge

Minnegasco proposed a New Area Surcharge Rider that would allow it to extend service to areas where service cannot be economically justified under Minnegasco's present rates. The New Area Surcharge Rider would allow Minnegasco to add a fixed monthly surcharge to customer bills for no longer then 10 years or whenever Minnegasco recovers its incremental cost of providing service to the new area, whichever comes first.

The Department agreed that a New Area Surcharge would be appropriate but objected to Minnegasco's proposal because it did not contain enough details for the Department to make an evaluation and did not conform to the New Town Rate that was approved for Northern Minnesota Utilities in Docket No. G-007/M-92-212.[13] The Department recommended rejecting the New Area Surcharge Rider and requiring the Company to make a separate miscellaneous tariff filing. The Department argued that this would ensure the Rider received an adequate level of review.

The Company agreed to redesign its tariff in conformance with Northern Minnesota Utilities' New Town Rate but proposed to do this as part of its compliance filing in this rate case.

The ALJ recommended approving a New Area Surcharge Rider for Minnegasco as consistent with the Commission's decision regarding Northern Minnesota Utilities' New Town Rate. The ALJ recommended allowing Minnegasco to make its revised filing a part of its rate case compliance filing and suggested allowing parties additional time to comment on this particular issue. In response to questions during Oral Arguments the Department stated that it would not object to reviewing the Rider as part of the rate case compliance filing.

The Commission believes that a New Area Surcharge Rider is appropriate but that it will need to review the Company's modified language of that rate before granting final approval. The Commission finds that review of the modified rate language in a compliance filing will afford adequate opportunity to address the issue. Therefore, the Commission will approve Minnegasco's modified New Area Surcharge Rider provisionally, i.e. subject to review in the Company's compliance filing.

### P. Reconnection Charges

Minnegasco proposed an increase for all customer reconnection charges to $35 from the current level of $10 for customers who have had their meter locked for non-payment of their bill and $20 for customers who have had their meter removed for non-payment of their bill. Minnegasco argued that it costs the same to reconnect a customer regardless of the reason service is terminated and that charging a below cost reconnection charge to some of its customers sends an inaccurate price signal about the cost of not paying the gas bill.

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[13] In the Matter of a Request by Northern Minnesota Utilities for Approval of a New Town Rate, Docket No. G-007/M-92-212, ORDER APPROVING TARIFF WITH MODIFICATIONS AND REQUIRING FURTHER FILING (May 6, 1992).

The Department objected to Minnegasco's proposal and suggested that the reconnection charge for non-payment of a bill should be $15 and the reconnection charge for all other reasons such as meter tampering should be $35. The Department argued that it is more important to maintain access to service for low income ratepayer who have trouble paying their bills than it is to send the correct price signal about reconnection charges. The Department argued that it was important to try and maintain these people on the system and that a too high reconnection charge would prevent them from getting back onto the system after a disconnection. The Department did not object to the $35 reconnection charge for meter tampering, breach of contract and fraudulent use of services.

The ALJ recommended adopting the Department's proposal for a $15 and a $35 reconnection charge depending on the Company's reason for disconnecting the customer's service. The ALJ believes that customers should not be penalized for reasons due to economic hardship to the same extent as customers who wrongfully avail themselves of the Company's property and services.

The Commission agrees with the Department's and the ALJ's recommendation for a $15 reconnection charge for non-payment of a bill. The Commission finds that a higher charge may contribute to another cycle of non-payment of bills.

The Commission also finds that a $50 reconnection charge for reasons other than non-payment of a bill would be more appropriate than a $35 charge. The Commission believes that a higher reconnection charge for customer malfeasance will help offset some of the cost of allowing a lower reconnection charge for customers who are disconnected for non-payment of their bill. The Commission finds this two-fee rate structure is consistent with its decision in the 1991 NSP-Electric rate case.[14] In that case, the Commission viewed the relock issue with the utmost seriousness and found that customer tampering with Company equipment is a violation of the law as well as a safety hazard and an infringement on the Company's right to disconnect service for non-payment.

### Q. Seasonal Sales Cooling Service Rider

The Company proposed a Seasonal Sales Cooling Service Rider for separately metered, gas powered, energy efficient, air conditioning equipment that would make interruptible rates available to these customers off-peak between April 15 and October 15. The Company argued that this would encourage

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[14] In the Matter of the Application of Northern States Power Company for Authority to Increase its Rates for Electric Service in the State of Minnesota, Docket No. E-002/GR-91-1, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER (November 27, 1991).

investment in gas powered air conditioning equipment, help the Company improve its off-peak system load factor and reduce the amount of electricity needed for summertime air conditioning.

The Department objected to the Company's proposal to offer a reduced rate to customers based on the customers' end-use for the gas. The Department argued that rates should be based instead on cost of service and load characteristics and that only if the customer meets the established criteria for a reduced rate should the customer be entitled to the reduced rate. The Department also argued that if the Company wanted to request permission to recover funds invested in natural gas air conditioning equipment because of potential conservation benefits, then the appropriate place to make that request would be in a CIP plan budget proposal.

The ALJ agreed with the Company and found that the use of gas for summertime air conditioning is likely to improve the Company's overall load curve to the advantage of all of its customers. The ALJ also found that it would be in the public interest to allow this rider because it would help reduce demand for electricity when electric utilities are at their summertime peaks. The ALJ did not agree with the Department's argument that the appropriate place to make this kind of proposal was in the Company's CIP plan.

The Commission agrees with the Department and will not allow the Company to charge natural gas air conditioning customers a reduced rate because of their end use for the gas. The Commission finds that rates should be based on a customer's load characteristics and that to qualify for an interruptible rate a customer will have to meet the criteria established in the Company's tariffs for those rates.

### R. Water Pumping Sales Service Rider

Minnegasco proposed to reduce the Commercial and Industrial energy charge for municipal water pumping customers. The Company argued that a lower rate for these customers would promote the use of natural gas powered water pumping equipment and improve the Company's overall load curve.

The Department objected to the Company's proposal because it would make a reduced rate available to a customer on the basis of the customer's end-use for the gas. The Department argued that rates should be based on load characteristics and cost of service. The Department argued that municipal water pumping customers should receive whatever rate they are entitled to on the basis of how much gas they use and whether they are willing to be interrupted rather than on the basis of a seasonal difference in gas usage.

The ALJ recommended approving the rider because of its potential for improving the Company's overall load curve and for decreasing the demand for electricity in the summer. The ALJ believes these potential benefits outweigh any harmful impact rate discrimination might have on the Company's other Commercial and Industrial customers.

The Commission agrees with the Department and will not approve a reduced Commercial and Industrial rate for municipal water pumping customers because of their end use for the gas. The Commission finds that rates should be based on a customer's load characteristics and that to qualify for a reduced rate a customer will have to meet the criteria established in the Company's tariffs for the reduced rate.

### S. Natural Gas Vehicle Service Rider

Minnegasco proposed a Natural Gas Vehicle Service Rider that would allow it to give a $2.00 per Mcf credit to Commercial and Industrial Sales Service customers who use natural gas as fuel for dedicated natural gas vehicles (NGVs). Under Minnegasco's proposal for a customer to qualify for this rate all NGVs would have to run exclusively on compressed natural gas, the customer would have to own and run its own gas compressor and the gas would have to be separately metered. In addition, the rate would only be available for a term of four years and would be used to help defray the cost of investing in dedicated NGVs.

Minnegasco argued that the use of alternate fuels in NGVs would reduce the level of air pollution and reduce the United States dependence on foreign oil. Minnegasco argued that these are compelling public policy reasons for approving this rider.

The Department objected to the Company's proposal because it would be a discriminatory rate based on end use rather than load characteristics or cost of service. The Department argued that Minnegasco's ratepayer should not be expected to subsidize private investment in NGVs. The Department also argued that if there are compelling public policy reasons that warrant subsidizing investment in NGVs then the Company's shareholders or taxpayers should pay for those subsidies.

The Department also argued that gas for use in dedicated NGVs is a year-round load and would add capacity costs during the winter as well as the summer. The Department argued that if these customers are buying gas under the same conditions as other firm customers they should pay the same rates as other firm customers. But if they are willing to risk being interrupted then they should be entitled to an interruptible rate.

The ALJ recommended approving the rider because an increase in the use of alternate fuels in NGVs would help promote the public policy objective of cleaner air and reduced dependence on foreign oil.

The Commission agrees with the Department and will not approve a $2.00 per Mcf credit to the applicable Commercial and Industrial Sales Service rate for gas purchased for use in NGVs. The

Commission finds that the Company's proposal would create a discriminatory rate based on end use instead of a rate based on load characteristics and cost of service. The Commission finds that to the extent that the Company's proposal would help society attain cleaner air and reduce the United States dependence on foreign oil it would be more appropriate for Minnegasco (or the NGV owners) to seek recovery of the $2.00 per Mcf investment from all of the beneficiaries of the those policies rather than just Minnegasco ratepayers.

**ORDER**

1. Minnegasco is entitled to increase gross annual Minnesota jurisdictional revenues by $11,512,000 in order to produce total gross annual jurisdictional operating revenues of $462,618,256.

2. Within 30 days of the date of this Order, the Company shall file with the Commission for its review and approval, and serve on all parties in this proceeding, revised schedules of rates and charges reflecting the revenue requirement and the rate design decisions contained herein, along with the proposed effective date.

3. The compliance filing filed pursuant to Ordering Paragraph 2 shall contain:

   a. Schedules showing all billing determinants collecting the total annual gross operating revenues from the sale of gas in the amount of $460,399,256. These schedules shall include but not be limited to:

      1. Total revenue by customer class,
      2. Total number of customers, the customer charge and total customer charge revenue by customer class,
      3. Total number of commodity related billing units, the per unit commodity and demand cost of gas, the non-gas unit margin and total commodity related sales revenue by customer class.

   b. A revised version of the Company's Gas Rate Book incorporating the rate design decisions contained in this Order and including but not limited to the following:

      1. The $5.00 per month Residential Class customer charge and the customer charges contained in the stipulation,
      2. The stipulated class revenue apportionments,
      3. The Process Interruptible Sales Service Rider as agreed to by the parties,

4. The main and service line footage allowances extension charges as agreed to by the parties,
5. The extension of the late payment period for the C&I customer class by 10 days to correspond to the Residential customer class late payment period,
6. Therm billing,
7. The tariff changes not specifically referred to in this order except in Section XIII, J that are of a housekeeping nature,
8. The addition of the last sentence in Minnegasco's proposed language on continuity of service to the existing tariff on Maintenance and Responsibility,
9. The tariff language on Minnegasco's Right to Remove a Gas Meter as agreed to by the parties,
10. Minnegasco's customer deposit tariff language,
11. The renaming of the No Charge Service tariff to No Surcharge Service,
12. The increased reconnection charges of $15.00 and $50.00 depending on the reason for disconnection.

c. Proposed customer notices explaining the final rates.

d. A proposal for a separate customer notice on therm billing to be distributed in customer bills when therm billing goes into effect.

4. Within 30 days of the date of this Order, the Company shall file with the Commission and serve on the parties, a revised base cost of gas and supporting schedules incorporating the changes made herein. The Company shall also file its automatic adjustment establishing the proper adjustment to be in effect at the time final rates become effective. The Department shall review these filings as it does other automatic adjustment filings.

5. Within 30 days of the date of this Order, the Company shall file with the Commission for its review and approval, and serve upon all parties to this proceeding, a proposal to make refunds, including interest calculated at the average prime rate, or other appropriate adjustments, to affected customers. The proposal shall reflect the difference between the revenue collected during the interim rate period and the amount authorized herein.

6. Within 30 days of the service date of this Order, the Company shall file proposed extension tariff language that includes an economic feasibility formula detailing the conditions under which Minnegasco can waive extension charges and requiring the Company to collect advances-for-construction and make refunds under certain conditions.

7. Within 30 days of the date of this Order, the Company shall file with the Commission for its review and approval, and serve on all parties in this proceeding, a modified New Area Surcharge Rider as discussed herein.

8. Parties shall have 15 days to comment on the filings required in Ordering Paragraphs 1 through 7.

9. Within 60 days from the date of this Order, the Company shall file an update of its MGP cleanup cost recovery activities to date, including what claims it has filed, and what efforts it has made to identify and recover costs from other potential parties. Minnegasco shall also file information showing what future actions it plans to take and a schedule of those activities with regard to recovery of its MGP costs from insurance companies and other parties.

10. Within 60 days from the date of this Order, the Company shall file a report that explains and defines the categories of expenses that Minnegasco proposes to classify and recover as MGP cleanup costs.

11. Within 60 days of the date of this Order, the Company shall file with the Commission and serve on the parties a filing detailing which programs are eligible for lost margin recovery and the associated energy savings goals. Parties shall have 30 days to comment on this filing.

12. On an annual basis, beginning no later than November 1, 1994, instead of its current annual filing date, the Company shall file with the Commission and serve on the parties its annual conservation tracker account report. This report shall include conservation costs incurred, the conservation costs recovered, and the balance in the tracker account. This report shall also include the Company's calculations of actual lost margins and energy savings goals achieved due to its conservation efforts. Parties shall have 30 days to comment on these filings.

13. On an annual basis, beginning April 1, 1994 the Company shall file with the Department, an update of FAS 106 funding. This update shall include: 1) the existing funding situation; 2) tax-deductible alternatives available to Minnegasco; 3) a five year forecast of future funding levels; 4) the amount of equity in Arkla's and Minnegasco's capital structures; and 5) the existing post retirement benefit obligation.

14. Minnegasco shall file on an annual basis the amount of its expenditures for the year and its cumulative expenditures to date for MGP costs. The annual reporting of these costs shall explain and show the types of costs that were incurred and what monies were recovered from insurance companies and other parties. This information shall be filed by April 1st of each year.

15. Minnegasco, in its next rate case, shall file information and provide calculations showing the impact on proposed final and interim rates of using an industry average capital structure. Minnegasco shall also file information

describing the effect of manufactured gas plant cleanup costs, incentive compensation, vacation accruals, and winter leak surveys on test year costs and rate base.

16. Minnegasco, in its next rate case, shall develop a proposal for a three-part rate for its Large-Volume Commercial & Industrial Sales Service customer class.

17. This Order shall become effective immediately.

BY ORDER OF THE COMMISSION

Richard R. Lancaster
Executive Secretary

(S E A L)

## DISSENTING OPINION

Commissioners Storm and Burton, dissenting.

**I. Introduction**

In a generally accepted model of utility regulation, utilities as regulated monopolies give up certain marketplace opportunities and choices which are allowed nonregulated entities. Their regulators in turn permit the regulated utilities to present evidence of their revenue requirements in rate cases. A properly presented rate case will allow a utility to recover its prudently incurred expenses, plus a reasonable return on its investment.

As will be shown in the body of this dissent, Minnegasco did not overstep the bounds of the regulatory model in its treatment of prudent post-retirement employee benefits. Neither did Minnegasco fail in its burden of proof when it presented those expenses for recovery in its rate case. In addition, Minnegasco consistently abided by specific Commission requirements in its accounting treatment of the expenses.

Despite these facts, the majority has chosen to disallow a significant portion of Minnegasco's prudently incurred SFAS 106 expenses. We respectfully dissent from that portion of the majority opinion.

**II. Factual Background**

In the past, Minnegasco recorded PBOP expenses on a cash basis. In doing so, Minnegasco acted in accordance with standard utility practice. The ALJ recognized the prudence of Minnegasco's past accounting practices in Findings No. 46 and 53 of the ALJ's report. The Commission also found that Minnegasco's past treatment of PBOPs on a PAYGO basis was prudent. Order at p. 12.

In 1990 FASB changed its accounting standards for PBOPs from the cash basis to the accrual basis. The Commission issued its official response to the change in its September, 1992 ORDER ADOPTING ACCOUNTING STANDARD AND ALLOWING DEFERRED ACCOUNTING in Docket No. U-999/CI-92-96 (the FASB docket). In that Order the Commission stated:

> The Commission adopts SFAS 106 accrual accounting for Minnesota utility recordkeeping and ratemaking purposes, subject to Commission review for prudence and reasonableness of the [PBOP] programs, expenses, and all calculations in future rate cases.
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> Order at p. 6.

The Commission also established a process for utility changeovers to the new accounting method. The Commission authorized a three year deferred accounting period for utilities, with the deferred balance of PBOP expenses subject to Commission general rate case review. In its November 2, 1992 ORDER DENYING PETITION FOR RECONSIDERATION, GRANTING IN PART AND DENYING IN PART PETITIONS FOR CLARIFICATION in the FASB docket, the Commission clarified that deferred balances which were not brought forward for rate case review within the allowed three year period would be denied recovery.

On July 2, 1992, Minnegasco filed a general rate case in which it sought, among other things, recovery of its PBOP expenses. Test year PBOP expenses consisted of three component parts:

1. The year's service cost, the present value of the future benefits earned by current employees during the year;

2. The interest cost, equal to the discount rate used to determine the present value multiplied by the accumulated present value, of the total of expected future PBOPs;

3. The amortization of the transition obligation, which is defined as the present value of the accumulated expected future PBOP liability on the day SFAS 106 is adopted.

The Commission found that the current service component of Minnegasco's PBOP expenses was "reasonable, prudent, and recoverable in rates." Order at p. 10. The ALJ also recommended complete recovery of the transition obligation, together with interest. The majority, however, disallowed one half of the transition obligation component, and one half of the associated interest.

**III. Analysis**

Analysis of Minnegasco's treatment of PBOPs brings us to the firm conclusion that the majority erred when it disallowed one half of the transition obligation and associated interest. Minnegasco experienced normal and ordinary expenses when it incurred liability for employees' post-retirement benefits. This category of expense is considered a normal cost of service in utility accounting, and is consistently treated as such in rate cases before the Commission. Prior to FASB accounting changes, Minnegasco accounted for the expenses in a manner consistent with prevailing industry practice and approved by the Commission in the Company's rate cases. Minnegasco changed to accrual accounting for PBOPs for ratemaking purposes in response to the Commission's direction in the September 22, 1992 Order addressed to all utilities. After Minnegasco's accounting change took place, the Company proposed an ongoing PBOP accounting plan in this rate case; neither the prudence of the plan nor its calculations was contested. Since the new accounting plan, pursuant to Commission direction, was based on the accrual method, a transition obligation was an inevitable and integral part of the proposed rate case expenses.

After reviewing this history, we are convinced that there was no action by Minnegasco at any time which converted a normal, ordinary, prudently incurred business expense into something for which shareholders should be penalized by disallowance. (Indeed, it is unclear how Minnegasco could have prudently made any other decisions throughout this period.) The benefits paid to employees and the timing of the payments are exactly the same under the PAYGO and the accrual methods. The character and the amount of the obligation remain unchanged; only the manner of booking the expense for accounting purposes changes. Nothing increases ratepayer liability or renders a prudent cost imprudent. An accounting change should not distract the Commission from its basic examination of the prudence and reasonableness of costs of service for rate case recovery. The PBOP costs under the accounting change, including the transition obligation and associated interest, were reasonable and prudent and should be recovered in full.

Because Minnegasco adhered to sound regulatory practice in its treatment of PBOP costs and in its presentation of the expenses for rate case recovery, the Company should recover these prudent costs of utility service. We believe that this fundamental principle is ignored or misunderstood in the majority opinion. No reasoning offered by the majority convinces us otherwise.

1. The Test Year Concept

The majority focuses strongly upon a philosophical discussion of the test year principle. We agree with the majority that the test year is a useful device for balancing revenue and expense to arrive at a revenue requirement. However, nothing in the basic concept of the test year requires disallowance of these PBOP expenses.

The majority states that the transition obligation is an out-of-test year expense and therefore cannot be recovered. (Although, inexplicably, the Company is later allowed to recover one half of the transition obligation). In actuality, the obligation <u>was</u> recognized in the test year.

The majority lists a host of regulatory evils against which the test year concept stands as a bulwark. We believe that even if the transition obligation were considered an out-of-test-year expense, none of the cited evils would be present in this case. As will be explained later, there is no inequitable intergenerational matching present. The costs for which recovery is sought are "representative, not aberrant." There is absolutely nothing in the record to indicate that the proposed expenses are based on "conjecture" instead of "facts and experience." On the contrary, the expenses were determined carefully and precisely, using calculations accepted by all the parties. There is no need for the test year to act as a "regulatory safeguard against under-recovery, overrecovery, [or] imprecision in ratemaking" in this case.

In short, the Commission should continue to view the test year as a tool in arriving at the revenue requirement component of just and reasonable rates. The test year concept should not overshadow considered Commission judgment on the prudence and reasonableness of incurred expenses.

2. The Matching Concept

The majority holds that one half of the transition obligation should be disallowed because it produces an improper match between the time a cost is incurred and the recovery of that cost. The truth is that neither PAYGO or SFAS 106 accrual accounting, or any other accounting method, produces a perfect match. The SFAS 106 method, however, is a move toward better matching.

Under the PAYGO method, liability is incurred when service is rendered in the present, but that liability or cost is not recognized until benefits are paid in the future. If the incurring of a future liability is recognized as a present cost, as under SFAS 106 accounting, PAYGO may be viewed as the ultimate mismatch.

Under the SFAS 106 accrual method, the present value of future liabilities is booked at the time those liabilities are incurred, when present service is rendered. SFAS 106 accounting achieves a better match of the incurring of the obligation with both recognition of the cost and recovery from ratepayers. Because the transition obligation is an integral part of the changeover from cash basis to accrual basis, it is part of the move to better matching. The transition obligation actually accelerates the matching process, allowing recovery to rest with present ratepayers, who are more likely than future ratepayers (who would pay under PAYGO) to have rendered the service from whence the transition obligation arose.

The majority seems to believe that the transition obligation produces a mismatch which is akin to retroactive ratemaking. "It results in one group of ratepayers bearing expenses that would have been charged to another group, given perfect information earlier." Order at p. 4. In its September 22, 1992 Order, the Commission specifically found that the transition obligation does not result in retroactive ratemaking:

> While under pay-as-you-go accounting [PBOP] expenses are recognized at the same time as they are paid out to employees, the employee services from which the benefits arose occurred in the past. This imperfect matching of expense recognition with employee services also occurs if a transition obligation is recognized. Recovery of [PBOP] costs under pay-as-you-go accounting has never been considered retroactive ratemaking, and neither should the recovery of a transition obligation which arises as a result of a change to accrual accounting. Neither of these situations is the type of reaching back for past costs which

> the retroactive ratemaking doctrine prohibits. The utility is not in either case attempting to recover in current rates costs which should properly have been recovered in past rates.
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> Order at pp. 5-6.

3. The Benefits to Shareholders

The majority disallows one half of the transition obligation amount because the transition obligation "... benefits investors so significantly that apportioning part of the transition cost to them is reasonable." Order at p. 4. We find this reasoning flawed.

The SFAS 106 benefits to shareholders mentioned by the parties are more accurate financial reporting and more precise identification of costs. There is nothing in the record to show that these benefits would not result in more prudent managerial decisions, benefiting ratepayers at least as much as shareholders. More accurate financial reporting and identification of costs impose no burden or higher cost on ratepayers; employee benefit payouts remain unchanged after the switch to accrual accounting. There is absolutely no reason to penalize shareholders by a 50% disallowance because an accounting change has brought about greater accuracy and accountability in company recordkeeping and financial reporting.

4. Extraordinary Expenses

The majority states that a disallowance of employee benefit expenses would be "... consistent with Commission action in other cases involving extraordinary expenses that do not fit within established rate case categories." PBOP expenses, however, are not extraordinary expenses, but normal and ordinary costs of providing utility service. The only meaning of the term "extraordinary" which could possibly be applied to these expenses is a definition found in Webster's Third New International Dictionary: "not of the usual order or pattern." The only thing "not of the usual" about these expenses is the one-time change in their recognition from cash basis to accrual. This accounting change does not render an ordinary, normal and necessary cost of providing service into something extraordinary, for which disallowance is justified.

5. Other Regulatory Bodies

The majority cites actions taken by other regulatory bodies as justification for the disallowance of Minnegasco's expense. The majority notes a partial disallowance of coal tar clean up costs by the Illinois Commerce Commission and a partial disallowance of the costs of a management incentive plan by the Vermont Public Service Board.

These cited regulatory actions do not involve sets of facts similar to those before the Commission. Neither case addresses disallowances of otherwise inarguably ordinary and prudent expenses because of changes in booking the expenses. In cases in which regulators have addressed SFAS 106 accounting questions, the expenses, including the transition obligation, have been allowed. Wisconsin and California public utility commissions, as well as others, have adopted SFAS 106 accounting, including the recognition of the transition obligation for ratemaking purposes. The Federal Energy Regulatory Commission has endorsed the policy of allowing recovery of the transition obligation. While these decisions certainly do not bind our Commission, they are instructive.

**IV. Conclusion**

Within the framework of utility regulation, regulators have a responsibility to both ratepayers and utility shareholders. This is intrinsic to the dynamic "give and take" of the regulatory model.

Public utility commissions have the duty to ensure that ratepayers are provided high quality service at fair and reasonable rates. Ratepayers must be protected from discriminatory and unfair treatment by regulated monopolies. Goals of universal service must be promoted when possible.

Regulators also have a responsibility to utility shareholders. Shareholders have a right to expect that prudent and reasonable managerial decisions will allow them to achieve a reasonable return on their investment, comparable to returns made on investments and other business undertakings of corresponding risks and uncertainties. Shareholders have a right to regulatory decisions which will enable the utility to maintain its financial integrity and attract new capital on reasonable terms. See, Bluefield Water Works and Improvement Co. v. P.S.C., 262 U.S. 679 (1923) and FPC v Hope Natural Gas Co., 320 U.S. 591 (1944).

For the reasons stated in this dissenting opinion, Minnegasco has the right to recover its prudent expenses for post-retirement employee benefits, including the transition obligation inherent in the Commission-sanctioned accounting method. Allowing Minnegasco full recovery of these prudent and reasonable costs of service would fulfill the Commission's responsibilities toward both ratepayers and shareholders.

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| Signed ______________________ | ______________________ |
| Don Storm | Tom Burton |
| Chair | Commissioner |

Date: ______________________